Commission review of the prudence of capacity acquisition related costs or the prospect of having some of those costs disallowed.

Some limited flexibility may be necessary to allow the gas utilities to react quickly to opportunities in the short term gas markets. However, the number and scope of such opportunities will be limited by the utilities' medium and long-term contracts.

Moreover, there will be many instances in which the utilities would not have to move quickly to secure the new supplies or pipeline capacity, such as in the decisions to renew existing contracts or to exercise RFOR or evergreen options. There is no need for the utilities' proposed pre-approval in such instances.

The Commission should not adopt the pre-approved process presented in the utilities' Phase 1 Proposals unless the utilities can offer specific evidence that without the requested pre-approval of capacity acquisitions they would be unable to secure adequate gas supplies from existing and new sources. Even then, the Commission should limit the pre-approval process to only those classes of capacity acquisitions or instances where there is a demonstrated need for the gas utilities to take actions quickly and ratepayers can be expected to benefit from the change.

The gas utilities need not fear subsequent Commission review of the prudence of their capacity acquisition decisions if they are able to fully document the bases of those decisions and can show that they were reasonable under the circumstances that existed at the time they were entered into and that the company fully considered all reasonable demand and supply options.

Comment No. 3: The gas utilities' proposals would allow for only minor stakeholder input or review of their gas capacity acquisition decisions.

The SoCalGas and PG&E Phase 1 Proposals commit the companies to "consult" with TURN as part of their authorized capacity commitment processes.[23] However, the exact nature of this consultation is unspecified. Moreover, there is no commitment by the utilities to follow or even fully consider any of the concerns raised by or the recommendations made by TURN. No other representatives of stakeholders, other than the Commission's Energy Division and ORA, would be consulted before the Companies entered into the categories of commitments specified in each company's proposal. The SDG&E Phase 1 Proposal does not even include a commitment to consult with TURN or any other stakeholder other than the ORA and the Energy Division.

The utilities' also propose an Expedited Capacity Advice Letter process in which the acquisition of capacity outside of their pre-approved ranges would be reviewed by the Commission. Although the specifics differ between the utility proposals, these Expedited Capacity Advice Letters would be used in situations where the utilities were seeking to

[23] *Phase 1 Proposals and Data Response of Respondent Pacific Gas and Electric Company*, dated February 24, 2004, at page 11 and *Proposals of San Diego Gas & Electric Company and Southern California Gas Company*, dated February 24, 2004, at page 26.

obtain new capacity for terms of longer than three years or beyond pre-approved quantities.

As proposed, the Expedited Capacity Advice Letter process would allow interested parties ten days to submit protests and comments and three days for replies, and would seek Commission approval within 21 days of the filed date. Consequently, there would be no opportunity before filing their protests and comments for interested stakeholders to do any discovery to elicit information from the utility about the other supply and demand alternatives that were available and considered. Nor would there be any hearings or opportunity to cross-examine the utility's claims. In this system, in order to provide meaningful comments on proposed capacity acquisitions, interested stakeholders would need significant budgets sufficient to maintain full-time monitoring of the gas supply and demand situations and alternatives.

Comment No. 4: The Commission should not be rushed into approving by this summer the fundamental changes in natural gas regulation that have been proposed by the natural gas utilities.

The Commission's Order instituting this ratemaking expressed concern that the Phase 1 issues had to be resolved by this summer. Not surprisingly, the Phase 1 Proposals submitted by the natural gas utilities echoed the sentiment that the Commission needed to approve the requested changes in traditional ratemaking and oversight by this summer. However, the proposals submitted by the utilities were devoid of any concrete evidence showing that the Commission needed to decide these issues that quickly. Indeed, the utilities' Phase 1 proposals contained evidence which shows that the Commission need not rush to judgment in this proceeding.

First, the only SDG&E pipeline contract that has an upcoming termination notice date before the end of May 2005 is the relatively small Canadian Path contract with Trans-Canada Nova Gas Limited which has a notice date of October 31, 2004. This contract provides for 17,375 Mcf/day of capacity.[24]

Second, SoCalGas has two substantial contracts with Transwestern which have RFOR dates of November 1, 2004.[25] However, SoCalGas already has stated its intention to terminate or to negotiate reduced amounts of capacity on its contracts with Transwestern or El Paso. Consequently, it is inconceivable that SoCalGas has not already been evaluating possible alternative sources and developing plans to replace part or all of the two contracts which have November 1, 2004 RFOR dates.

Similarly, PG&E has three contracts with GTNC, TransCanada BC and TransCanada NOVA which expire in late 2005 and have notice dates of October 31 and December 31, 2004. However, PG&E has expressed satisfaction with its existing natural gas supply sources and pipeline contracts:

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[24] Table Q4 of SDG&E's Responses to CPUC Data Requests (R.04-01-025).

[25] Table Q4 of SoCalGas's Responses to CPUC Data Requests (R.04-01-025).

> One of the issues the Commission has asked the parties to address is supply diversity. PG&E is currently exceptionally well-situated to purchase natural gas from a variety of competing sources in Canada and the U.S. Southwest. PG&E's pipeline capacity contracts are structured to afford PG&E the opportunity to purchase gas from these competing sources. PG&E's comments herein are intended to preserve and expand upon this existing level of supply diversity.[26]

As with SoCalGas, it is inconceivable that PG&E has not already been evaluating possible alternative sources and deciding whether to terminate or replace some of the pipeline capacity provided by these three contracts.

Consequently, the Commission certainly does not need to make any decision in the Phase I proceeding before late October 2004, if not later. Moreover, the Commission can use the intervening seven months to examine the reasonableness of the plans that these three companies have for renewing, replacing or terminating their pipeline contracts within the context of a proceeding allowing for hearings and public participation.

Comment No. 5: Portfolio Management is the appropriate approach for securing adequate supplies of natural gas at reasonable rates.

The gas utilities say in their Phase I Proposals that it is important for them to obtain natural gas from a variety of supply sources and under a blend of short, medium and long-term contracts. We agree. Developing an optimal resource mix is essential for ensuring that there will be adequate supplies of natural gas to meet the demands of core and non-core customers and electric generators at reasonable rates and with minimal environmental impact.

Such an optimal mix should include demand side options and obtaining gas from diversified supply sources, under contracts of varying lengths and with some reliance on spot markets. Indeed, as California's Energy Action Plan recognizes, the implementation of cost-effective energy efficiency measures must be the first step in developing the optimal mix of resources. An optimal resource mix also can include financial and physical hedges.

However, the gas utilities have provided no evidence that they have carried out an integrated resource process to determine the appropriate mix of supply sources and contract terms. Until they provide such evidence, the Commission should withhold pre-adoption of any process that provides for any pre-approval of any resource acquisitions. Pre-approval of resources with some assurance of cost recovery should be used with great caution, and only if certain critical conditions are met. It is essential that pre-approval only be applied to resource portfolios that were developed with proper portfolio management techniques, with meaningful and substantial input from key stakeholders, and with proper oversight from regulators.

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[26] *Phase I Proposals and Data Response of Respondent Pacific Gas and Electric Company*, dated February 24, 2004, at page 5.

Moreover, there should be no guarantees of full rate recovery of gas utility capacity acquisitions or related investments in the absence of a showing that the utility explored and considered all reasonable supply and demand side alternatives, including energy efficiency and the use of renewable energy sources, a showing that the utility used a methodology that recognizes both the economic and environmental benefits and costs of such alternatives, and a showing that the proposed new resources are absolutely essential for reliable service and clearly and materially superior on a societal least cost basis. Such evaluation and comparison should take into account the economic benefit reduced consumption provides by reducing the market power of gas and electricity suppliers, tempering volatility of gas and electric market prices, and reducing clearing prices in gas and electric markets, especially at times of highest prices.

Comment No. 6: Commission oversight is critical to achieving the goals of portfolio management

The Commission must maintain an active oversight role if it is to be assured that the natural gas utilities are pursuing an optimal mix of both supply and demand resources. The Commission cannot merely adopt a pre-approval process that, in essence, delegates both the oversight role and the determination of the appropriate resource mix to be pursued to the gas utilities themselves, with some involvement by the ORA, the Energy Division, and, in some instances, TURN.

Instead, the Commission must be actively involved in the development and implementation of the resource mix to be pursued by the utility:

- To ensure that there gas utilities have adequate funding for energy efficiency activities and that those activities are prudently designed and implemented.
- To assure that there is broad stakeholder input in the process. One of the more challenging aspects of portfolio management is in the balancing of the many different criteria for selecting the optimal resource portfolio. This balancing often involves trade-offs that affect different stakeholders differently. In order to ensure proper balancing of different interests, it is essential to allow the various stakeholders to provide input into the portfolio management process.

In addition, there must be periodic regulatory review of the portfolio management process. Successful portfolio management requires regulatory guidance and oversight on an on-going basis. This requires that regulators periodically review and assess the decisions and the actions of the portfolio managers. The utilities should have no reason to fear such periodic ex post reviews if they have adequately documented their capacity acquisition and investment decisions and the utilities' actions can be shown to have provided benefits to ratepayers and society that exceed their costs. Even in pre-approval regimes, the implementation of the process must still be monitored by the Commission, if only to identify needed changes in policy.

Consequently, the Commission should implement a periodic gas integrated resource process with the goal of assisting the utilities in developing optimal mixes of supply and demand resources, instead of adopting the pre-approval processes proposed by the gas utilities. The utilities would have some flexibility in implementing the resulting resources plans and there could, in certain circumstances, be limited pre-approval of a range of short-term capacity acquisitions. This could encourage the gas utilities to take advantage of acquiring capacity resources in those situations in which quick action is required.

This periodic gas integrated resource process could be coordinated with the Gas Reports filed by the utilities every few years and the periodic gas infrastructure reviews.

Comment No. 7: Conservation and renewable energy should be the cornerstone of California's plan for meeting future natural gas needs.

The State's Energy Action Plan was adopted last May by the CPUC, the California Energy Commission and the California Power Authority with the overall goal of ensuring that adequate, reliable, and reasonably priced electricity and natural gas supplies are achieved and provided through policies, strategies and actions that are cost-effective and environmentally sound for California's consumers and taxpayers.[27]

The Energy Action Plan envisions a loading order of resources in which the first priority is given to optimizing strategies for energy conservation and efficiency. However, the OIR and Phase 1 proposals focus exclusively on actions to increase supplies rather than incorporating those actions into an integrated plan that first reduces the state's demand for natural gas. This emphasis on supply side solutions is significant because it could cause the Commission to lose sight of the ways in which the demand for natural gas, and, hence, the supplies that are needed in future years, can be dramatically reduced.

Assessments by the California Energy Commission and other responsible organizations have identified a number of policies, strategies and actions that the Commission should require be implemented before it grants the fundamental changes in traditional regulatory oversight of natural gas capacity acquisition and investments decisions that the natural gas utilities are requesting in their Phase 1 Proposals. These policies, strategies and actions are discussed in the various assessments cited in Comment Number 8 and Comment Number 10 in this Report.

Comment No. 8: The demand for natural gas can be significantly reduced through the implementation of more extensive electric energy efficiency programs and the acceleration of the state's Renewable Portfolio Standard from 2017 to 2010.

Electric generation currently represents about 37 percent of the natural gas consumed in California each year. The Staff of the California Energy Commission has estimated that the gas demand for electricity will grow from 0.80 Tcf in 2003 to 0.93 Tcf in 2013, an annual growth of 1.5 percent per year.[28] However, analyses by the Energy Commission Staff show that this growth can be reduced or even reversed if achievable electric energy efficiency goals are adopted and met and the achievement of the 20 percent goal for the

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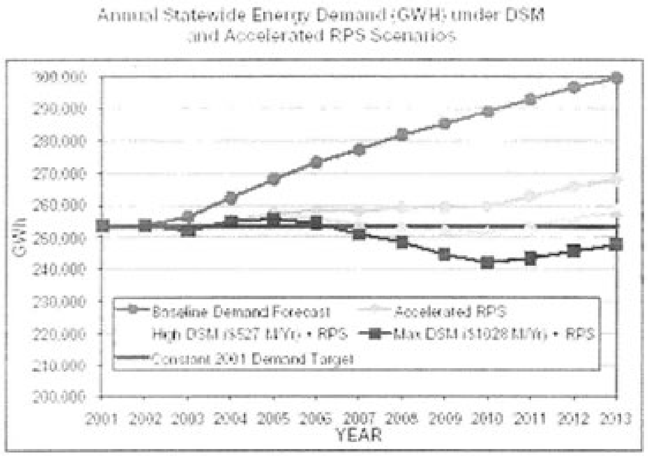
27 *Energy Action Plan Legislative Report*, dated January 5, 2004.

28 *Natural Gas Market Assessment*, California Energy Commission Staff Paper, August, 2003, at page 14.

state's renewable energy portfolio standard is accelerated to 2010 from the current goal of 2017.

Figure 1[29]



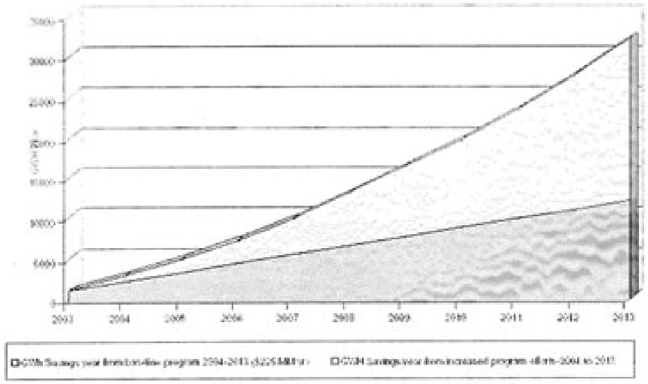
For example, the Energy Commission staff has recommended that the CPUC and the CEC set energy efficiency savings goals for the efficiency programs funded by the public goods charges and supplemental procurement programs. These goals are 7,000 GWh per year of savings from all energy efficiency programs by 2006, 13,000 GWh by 2008, and 30,000 GWh by 2013.[30]

29 *Public Interest Energy Strategies Report*, California Energy Commission Report, December 2003, at page 11.

30 *Proposed Energy Savings Goals for Energy Efficiency Programs in California*, California Energy Commission Staff Report, dated October 27, 2003, at page 1.

Figure 2[31]

Long Term Electricity Savings Goal for Energy Efficiency Programs



Meeting these goals would provide an additional 20,000 GWh of savings by 2013 (over the Energy Commission's base case forecasts) and would be equivalent to roughly 50 percent of the projected increase in electricity usage in the state over the next decade.[32]

A 2002 study on "California's Secret Energy Surplus, the Potential for Energy Efficiency," similarly concluded that over the next decade there is a significant remaining achievable and cost-effective potential for energy-efficiency savings in California, beyond the Business-as-Usual savings that are likely to occur under continuation of current public goods funding levels.[33] However, this study found that even higher levels of potential savings from energy efficiency than the CEC staff has recommended. In fact, Xenergy concluded that 40,146 GWh of electricity could be saved each year by 2011 through the implementation technically achievable and economic measures.[34] This would be more than 10,000 GWh above the goals proposed by the Energy Commission Staff.

Additional energy also will be saved over the next decade as a result of the recently adopted 2005 building standards. These standards provide a 10 percent improvement over the 2001 standard and include efficiency requirements for outdoor lighting, a first in the nation according to the January 2004 Energy Action Plan Legislative Report. These standards apply to all new construction and some commercial and residential remodels.

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31 Figure 7 in *Proposed Energy Savings Goals for Energy Efficiency Programs in California*, California Energy Commission Staff Report, dated October 27, 2003, at page 27.

32 The Energy Commission staff also found that additional savings could be achieved through improved building and appliance standards. Ibid, at footnote no. 1 on page 1.

33 *California's Secret Energy Surplus, the Potential for Energy Efficiency*, Xenergy, Inc., September 2002, at page 4-1.

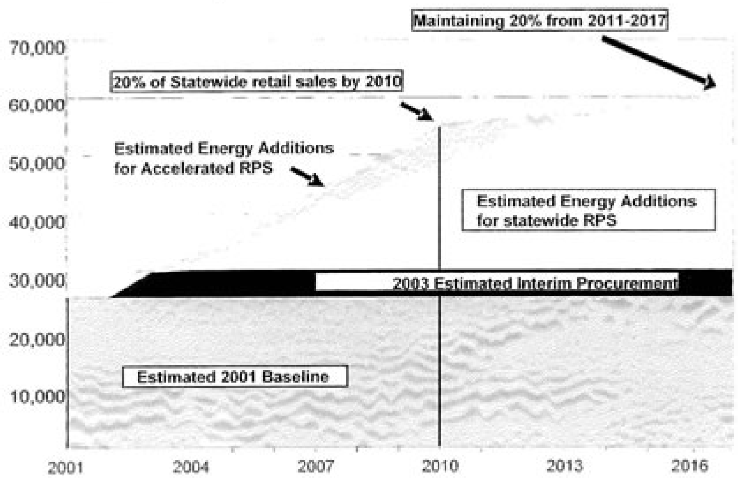
34 Ibid, at page 3-3.

They are expected to produce annual electricity savings of 1,800 MW and 4,750 GWh by 2016.[35]

Improved appliance standards also are expected to provide significant savings but these savings have not been quantified.

The Energy Commission Staff also has concluded that the remaining incremental system GWh needs in 2013, over the base demand in 2003, could be met through aggressive pursuit of the states Renewable Portfolio Standard for renewable generation plants.[36] For example, a Renewable Resources Development Report prepared by the CEC Staff found that accelerating the state's RPS to 20% by 2010 could produce 55,170 GWh of electricity from renewable energy sources by 2010.[37]

Figure 3[38]
Accelerating the Renewable Portfolio Standard to 2010



The Renewable Resources Development Report found that there are plenty of renewable energy resources in California to meet the current Renewable Portfolio Standard and the

35 *Energy Action Plan Legislative Report*, dated January 5, 2004, at page 1.

36 *Proposed Energy Savings Goals for Energy Efficiency Programs in California*, California Energy Commission Staff Report, dated October 27, 2003,at page 32.

37 *Renewable Resources Development Report*, , a Presentation by Ann Peterson, Project Manager, at the California Energy Commission Business Meeting, November 19, 2003.

38 *Renewable Resources Development Report*, a Presentation by Ann Peterson, Project Manager, at the California Energy Commission Business Meeting, November 19, 2003.

accelerated Renewable Portfolio Standard.[39] It also found that there are significant untapped renewable resources both in California and the other WECC states.

The November 2003 CEC Renewable Resources Development Report also emphasized that accelerating California's RPS was part of the integrated strategy identified in the state's Energy Action Plan to maintain fuel diversity in electric generation by:

- Reducing demand for electricity, especially during peak hours
- Accelerating development of renewable energy
- Replacing/repowering inefficient gas-fired generation.

Achieving the energy efficiency goals recommended by the Energy Commission staff and accelerating the RPS to 2010 could reduce electric energy usage in California in 2013 by an additional 25,000 GWh over base case Energy Commission Staff forecasts. This would reflect an additional 20,000 GWh of savings from increased energy efficiency program expenditures,[40] 3,000 to 4,000 GWh of additional savings from the 2005 building standards, and 1,000 to 2,000 GWh from the acceleration of the state's Renewable Portfolio Standard to 2010. Achieving these goals also would reduce the amount of natural gas used to generate electricity by approximately 155 Bcf per year.[41]

Some of this reduced gas usage would occur at power plants outside California, but it is not possible to determine how much without running a simulation of the integrated WECC system. But if even only half of the savings were to be from the displacement of generation at plants in California, the achievement of these savings would offset a significant portion of the 130 Bcf that the Energy Commission Staff has assumed the annual natural gas demand for electric generation will grow between 2003 and 2013. In addition, reduced natural gas use at power plants in other WECC states, due to energy efficiency programs in California and in-state generation by renewable sources, also would free up additional natural gas supplies that could be available for other uses in California.

Comment No. 9: Future natural gas demand also can be reduced significantly by the repowering or retirement of California's aging power plants.

There are approximately 16,600 MW of generating capacity at older natural-gas fired steam generating plants in California.[42] These units are generally more than 30 to 40

[39] Ibid.

[40] *Proposed Energy Savings Goals for Energy Efficiency Programs in California*, California Energy Commission Staff Report, dated October 27, 2003,at page 35.

[41] This estimate makes the conservative assumption that only 90 percent of the electricity that would be displaced by the increased energy efficiency and renewable energy output would have been generated at natural gas-fired plants. Synapse modeling and estimates from the California Energy Commission suggest that this figure might be between 95 and 100 percent.

[42] *Aging Natural Gas Power Plants in California*, California Energy Commission Staff Paper, July 2003.

years old, having been built in the 1950s, 1960s or early 1970s. All of these units have heat rates of 9,000 BTU/KWh or higher. Most have heat rates above 10,000 BTU/KWh.

These older, inefficient plants generated 60,961,190 MWh of electricity in 2001 and consumed approximately 593,420 Mcf of natural gas. As shown in Table 1 below, repowering just the older non-peaking plants in California with newer, combined cycle technology, with heat rates of approximately 7,000 BTU/KWh would save approximately 174 Bcf of natural gas each year. Retiring these aging power plants and replacing their generation with production by newer facilities at more remote sites would save slightly less natural gas due to transmission line losses.

Table 1
Potential Gas Savings from Repowering Aging Power Plants

		2001						After Repowering			
Plant Name	MW	2001 Capacity Factor (percent)	2001 Generation (MWh)	Approx. Heat Rate (BTU/KWh)	BTUs gas/year	Gas Heat Content (BTU/cf)	Unit 2001 Gas Use MMcf/year	Repowered Heat Rate (BTU/KWh)	Repowered BTUs gas/year	Repowered Unit Gas Use MMcf/year	Change from 2001 Gas Use (MMcf/year)
Moss Landing											
Units 6,7	1495	65	8,455,590	9000	7.61003E+13	1019	74,681	7000	5.9189E+13	58,084	-16,596
Alamitos											
Units 1,2	348	13	396,302	13000	5.15193E+12	1019	5,056	7000	2.7741E+12	2,722	-2,333
Units 3,4	642	46	2,587,003	11000	2.8457E+13	1019	27,926	7000	1.8109E+13	17,771	-10,155
Units 5,6	963	58	4,892,810	10000	4.89281E+13	1019	48,016	7000	3.425E+13	33,611	-14,405
Haynes											
Units 1,2	444	33	1,283,515	10000	1.28352E+13	1019	12,596	7000	8.9846E+12	8,817	-3,779
Units 3,4	444	17	661,205	10000	6.61205E+12	1019	6,489	7000	4.6284E+12	4,542	-1,947
Units 5,6	682	25	1,493,580	10000	1.49358E+13	1019	14,657	7000	1.0455E+13	10,260	-4,397
Ormond Beach											
Units 1,2	1492	42	5,489,366	10000	5.48937E+13	1019	53,870	7000	3.8426E+13	37,709	-16,161
Pittsburg power											
Units 5,6	632	60	3,321,792	10000	3.32179E+13	1019	32,599	7000	2.3253E+13	22,819	-9,780
Units 7	700	56	3,433,920	10000	3.43392E+13	1019	33,699	7000	2.4037E+13	23,589	-10,110
Redondo Beach											
Units 5,6	350	17	521,220	13000	6.77586E+12	1019	6,650	7000	3.6485E+12	3,581	-3,069
Units 7,8	967	44	3,727,205	10000	3.7272E+13	1019	36,577	7000	2.609E+13	25,604	-10,973
Morro Bay											
Units 1,2	342	30	898,776	11000	9.88654E+12	1019	9,702	7000	6.2914E+12	6,174	-3,528
Units 3,4	679	55	3,271,422	10000	3.27142E+13	1019	32,104	7000	2.29E+13	22,473	-9,631
Encina											
Units 1,2,3	320	40	1,121,280	11000	1.23341E+13	1019	12,104	7000	7.849E+12	7,703	-4,401
Units 4,5	635	44	2,447,544	11000	2.6923E+13	1019	26,421	7000	1.7133E+13	16,813	-9,608
Huntington Beach											
Units 1,2	430	37	1,393,716	9000	1.25434E+13	1019	12,310	7000	9.756E+12	9,574	-2,735
Scattergood											
Units 1,2	358	28	878,102	10000	8.78102E+12	1019	8,617	7000	6.1467E+12	6,032	-2,585
Units 3	445	25	974,550	10000	9.7455E+12	1019	9,564	7000	6.8219E+12	6,695	-2,869
Etiwanda											
Units 3,4	640	26	1,457,664	9000	1.3119E+13	1019	12,874	7000	1.0204E+13	10,013	-2,861
El Segundo											
Units 3,4	708	37	2,294,770	10000	2.29477E+13	1019	22,520	7000	1.6063E+13	15,764	-6,756
Contra Costa											
Unit 6	336	63	1,854,317	10000	1.85432E+13	1019	18,197	7000	1.298E+13	12,738	-5,459
Unit 7	336	52	1,530,547	10000	1.53055E+13	1019	15,020	7000	1.0714E+13	10,514	-4,506
South Bay											
Units 1,2	297	43	1,118,740	10000	1.11874E+13	1019	10,979	7000	7.8312E+12	7,685	-3,294
Unit 3	176	33	508,781	10000	5.08781E+12	1019	4,993	7000	3.5615E+12	3,495	-1,498
Unit 4	170	12	178,704	12000	2.14445E+12	1019	2,104	7000	1.2509E+12	1,228	-877
Coolwater											
Unit 1	65	43	244,842	10000	2.44842E+12	1019	2,403	7000	1.7139E+12	1,682	-721
Unit 2	82	57	409,442	10000	4.09442E+12	1019	4,018	7000	2.8661E+12	2,813	-1,205
Units 3,4	482	53	2,237,830	9000	2.01405E+13	1019	19,765	7000	1.5665E+13	15,373	-4,392
Mandalay											
Units 1,2	433	45	1,706,886	9000	1.5362E+13	1019	15,076	7000	1.1948E+13	11,725	-3,350
Valley											
Units 1,2	190	0	0	12000	0	1019	0	7000	0	0	0
Units 3,4	323	6	169,769	11000	1.86746E+12	1019	1,833	7000	1.1884E+12	1,166	-666
Total	16,536		60,961,190				593,420			418,772	-174,648

These aging power plants probably can be expected to generate less electricity in the future than they did in 2001 as a result of expanded energy efficiency programs and increased output from renewable energy sources and new more-efficient gas-fired units. In addition, some generation from more efficient gas-fired units located outside California also can probably be expected to displace some of the electricity that would otherwise be generated by these aging plants. However, some of the aging units in California are located within transmission constrained areas and, depending on transmission system improvements, can be expected to continue to generate significant amounts of electricity. Consequently, repowering/replacement of aging facilities remains a strategy that has the potential to save significant amounts of natural gas.

There also are other significant benefits from the repowering of aging power plants such as reduced fuel and operating costs and lower NO_x emissions. Water usage also would be dramatically reduced if the repowering is accompanying by conversion from a once-through to a closed-cycle cooling system.

Comment No. 10: There is a significant potential for reducing both core and non-core natural gas demand.

The California Energy Commission's Demand Analysis Office forecasts that the core natural gas demand will increase from 0.66 Tcf to 0.73 Tcf between 2003 and 2013, yielding an annual growth rate of 0.9 percent.[43] Non-core natural gas demand is expected to increase from 0.74 Tcf to 0.77 Tcf during the same period, which is an annual growth rate of only 0.4 percent.[44]

Viewed in terms of end-use consumption by different classes of customers, these forecasts reflect that the residential and commercial sectors' demand for natural gas is expected to grow at approximately one per cent per year.[45] The industrial demand growth is expected to be essentially flat, growing at 0.1 percent per year.

These forecasts assume that the 2003 levels of funding for utility energy efficiency programs will continue through 2011.[46] However, there appears to be widespread agreement among groups as diverse as Sempra Energy, the National Petroleum Council, the American Council for an Energy-Efficient Economy ("ACEEE"), and the Center for Energy Efficiency and Renewable Technologies that increased spending on efficiency programs can lead to significant reductions in natural gas demands.

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43 *Natural Gas Market Assessment*, California Energy Commission Staff Paper, August, 2003, at page 14.

44 Ibid.

45 *Natural Gas Market Assessment*, California Energy Commission Staff Paper, August, 2003, at page ii.

46 *Natural Gas Market Assessment*, California Energy Commission Staff Paper, August, 2003, at page 14.

For example, the National Petroleum Council has concluded that "greater energy efficiency and conservation are vital near-term and long-term mechanisms for moderating price levels and reducing volatility."[47]

A recent study by ACEEE has estimated that energy efficiency and conservation programs could reduce the residential and commercial use of natural gas in California by 4.8 percent by 2008.[48] Industrial use of natural gas could be reduced by 5.2 percent by 2008.[49] Achieving these reductions would save approximately 70 Bcf per year in total core and non-core demand in 2008 and 73 Bcf in 2013.

Unfortunately, there do not appear to be any comprehensive California-specific studies of the potential for reducing natural gas demand through efficiency programs. Nevertheless, California's gas utilities have themselves emphasized the potential savings from energy efficiency programs. For example, SoCalGas and SDG&E, have recently reported that:

- The current SoCalGas energy efficiency programs have been very effective, consistently exceeded goals and averaging over 1 Bcf per year in reductions.
- SoCalGas's core gas sales per capita decreased from about 193 therms in 1994 to approximately 175 therms in 2001.
- Customer response indicates that the demand for natural gas programs continues to exceed the current funding levels, which have remained constant for the past five years.
- Energy efficiency options are more cost effective because of higher gas commodity costs.[50]

PG&E has similarly reported that the potential for saving natural gas "remains high."[51] In fact, according to PG&E, almost 250 million therms (i.e., approximately 25 Bcf) of natural gas could potentially be saved by increased energy efficiency programs in the residential sector.[52] One hundred and ninety three million therms of natural gas (approximately 19 Bcf) could potentially be saved by increased energy efficiency programs in the commercial sector.[53] Approximately 200 million therms of natural gas

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47 *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy, Volume I, Summary of Comments and Recommendations.* A Report of the National Petroleum Council, September 25, 2003, at page 21.

48 *Natural Gas Price Effects of Energy Efficiency and Renewable Energy Practices and Policies*, ACEEE, December 2003, at page 17.

49 Ibid, at page 22.

50 *Demand* Reduction, a presentation by Geoffrey Ayres, Director Commercial/Industrial Markets, SoCalGas, SDG&E, as part of Panel II. A. - Demand Reduction at the December 9 and 10, 2003 Natural Gas Workshop.

51 *Demand Reduction Efforts*, a presentation by Dave Hickman, PG&E Manager, Customer Energy Management, as part of Panel II. A. - Demand Reduction at the December 9 and 10, 2003 Natural Gas Workshop.

52 Ibid.

53 Ibid.

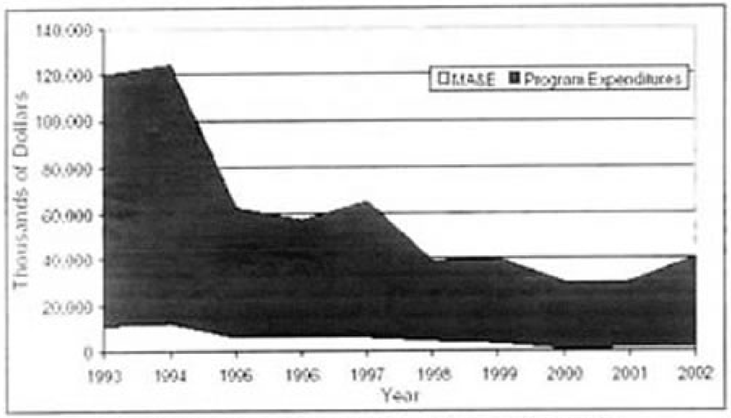
(i.e., 20 Bcf) could be saved in the residential and commercial sectors by just a doubling of the low energy efficiency funding levels of the mid-1990s.

The recently adopted 2005 building standards are expected to save 88 million therms (approximately 8 to 9 Bcf) of natural gas per year by 2016.[54]

Unfortunately, as shown in the following chart from the California Energy Commission, spending on gas efficiency programs has been dramatically reduced since the early 1990s.

Figure 4[55]

Natural Gas Efficiency Program and Evaluation Expenditure Trends



Annual spending on natural gas efficiency programs and evaluation has declined over the past decade.
Source: California Energy Commission and Xenergy

It appears clear that increased spending on energy efficiency programs has the potential to offset much, if not all, of the projected growth in core and non-core natural gas consumption. The Commission should adopt policies to spur the development and effective implementation of these programs.

By way of contrast, SDG&E and SoCalGas have assumed only relatively minor reductions in natural gas consumption in the forecasts that they have provided in response to Question 1 in OIR R.04-01-025. SDG&E assumed that for the period 2004-2006, the impact of energy efficiency programs would be a reduction in residential gas consumption of roughly 1.8 million therms. For the period 2007-2016, there was an assumed additional reduction of roughly 2.3 million therms.[56] These appear to be reductions of less than one percent of SDG&E's projected average year core gas demand in 2006 and 2016. These reductions are even smaller percentages of the utility's projected 2006 and 2016 core demands in the colder than average year scenarios.

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54 *Energy Action Plan Legislative Report*, dated January 5, 2004, at page 1.

55 *Public Interest Energy Strategies Report*, California Energy Commission, December 2003, at page 37.

56 SDG&E response to Question 1 in RACE's First Data Request.

In its response to Question 1 in OIR R.04-01-025, SoCalGas assumed reductions in core residential, commercial and industrial natural gas consumption of 2.244 Bcf in 2006 and 2.153 Bcf in 2016.[57] These also appear to be reductions of less than one percent of SoCalGas's projected average year core gas demand in 2006 and 2016. As with SDG&E, these reductions are even smaller percentages of SoCalGas's projected 2006 and 2016 core demands in the colder than average year scenarios.

Comment No. 11: PG&E's proposal that ratepayers continue to pay for existing facilities that are used less due to the addition of new supply sources or system capacity is contrary to established regulatory policy.

PG&E has proposed that it "not be penalized" if the addition of new supply or capacity results in some existing PG&E transmission or storage capacity being used less.[58] However, used and useful disallowances are a long standing traditional rate making principle. If the new supply or capacity results in lower cost service, but idles some existing capacity on a permanent basis, there should be some risk to the utility. It is established utility law that rates should provide an opportunity (not a guarantee) for a utility to earn a reasonable return on its investments, but only those investments used and useful for the provision of utility service. Where a resource is obsolete and not used and useful, the resource is, in general, removed from rate base (along with any corresponding reduction in the reserve for depreciation) and from current expenses.

If changing market circumstances that could not have been foreseen lead to the resource becoming not used and useful, despite prudent and economical management, a sharing of the costs that are not used and useful may be considered. One common way to do this, when sharing is deemed appropriate, is to allow recovery of the remaining investments over a reasonable period, say ten years, but without any return on the unamortized balance. At normal rates of return, this amounts to approximately a 50-50 sharing of the remaining investment in present value terms.

57 SoCalGas response to Question 1 in RACE's First Data Request.

58 *Phase I Proposals and Data Response of Respondent Pacific Gas and Electric Company*, dated February 24, 2004, at page 17.

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The Independent Risk Assessment (IRA) has been updated since issuance of the October 2004 Draft EIS/EIR. The lead agencies directed preparation of the current IRA, and the U.S. Department of Energy's Sandia National Laboratories independently reviewed it, as discussed in Section 4.2 and Appendix C.

Section 4.2.7.6 and the IRA (Appendix C1) discuss the models and assumptions used and the verification process. Sandia National Laboratories (Appendix C2) concluded that the models used were appropriate and produced valid results.

Exhibit 6

G437-288

Thomas O. Spicer, III, PhD, PE
Consulting Chemical Engineer
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Fayetteville, AR 72704

18 December 2004

Ms. Alicia I. Finigan
Environmental Defense Center
906 Garden Street
Santa Barbara, California 93110

RE: Review of Draft Environmental Impact Statement/Environmental Impact Report (EIS/EIR) for Cabrillo Port Liquefied Natural Gas (LNG) Deepwater Port (DWP)

Dear Ms. Finigan:

Per our agreement, I have reviewed the above captioned report particularly Section 4.2 Public Safety: Hazards and Risk Analysis and its discussion of thermal radiation and vapor dispersion hazards. This section summarizes assessment of the worst-case consequences associated with the proposed project and identifies objectives of the assessment process as (quoting from the report page 4.2-1):

- identify and evaluate potential hazards;
- define scenarios to bracket the range of potential accidents (resulting either from operations or terrorist attacks);
- use state of the art computer models to define the consequences for each scenario (including the worst-case scenario);
- compare the results to existing safety thresholds and other criteria; and
- make the results available to decision makers and the public, while also ensuring that release of relevant information does not in turn create a security threat.

This process has been conducted on the basis of an Independent Risk Assessment involving a team of experts commissioned to prepare a site-specific evaluation of the project. The Draft EIS/EIR summarizes the results of the Independent Risk Assessment but concludes that it contains sensitive security information which cannot be made available to the general public.

The Draft EIS/EIR bases its evaluation of the thermal and vapor dispersion hazards on several assumptions summarized in the report (page 4.2-19) including:

- High natural gas methane content.
- Wind profile is based on atmospheric stability class D.
- Wind speed at 33 feet (10 m) height above sea level is 13.4 mph (6 m/s)
- LNG is released instantaneously.

- Once spilled onto water, the LNG pool does not begin to evaporate "until the pool formed by a release has dispersed to a considerable distance. This assumption, coupled with the wind profile and speeds, is used to produce a conservative estimate (larger distance downwind potentially impacted by the release, which would be expected during a marine inversion) for horizontal dispersion of the LNG and the resulting natural gas cloud." (page 4.2-6)
- Each FSRU Moss storage tank contains 24 million gallons (91,000 m^3) of LNG.

Other assumptions would have been made as part of the assessment process, but such assumptions are apparently available only in the Independent Risk Assessment (such as the ambient humidity). In addition to these assumptions, the Draft EIS/EIR indicates the use of the Fire Dynamics Simulator (FDS) for the consequence estimates. Finally, the Draft EIS/EIR assigns a thermal radiation level (12.5 kW/m^2) and a natural gas vapor concentration level (equal to the lower flammable limit, LFL, for methane of 5%). In assessing the thermal radiation hazard, the Draft EIS/EIR seems to assume that an ignition source will become available only after the natural gas cloud has reached its maximum extent to the 5% level. From this analysis, the Draft EIS/EIR reports distances for three cases:

- Worst-Case Credible Release #1 (WC #1). Release of 50,000 m^3 LNG (one-half of one full tank) though a wall surface opening of 12.5%. The hazard distance was reported to be 2.0 km.
- Worst-Case Credible Release #2 (WC #2). Release of 100,000 m^3 LNG (one full tank) though a wall surface opening of 20 m^2. The hazard distance was reported to be 1.8 km.
- Terrorist Attack A (TA-A). Release of 300,000 m^3 LNG (three full tanks) instantaneously. The hazard distance was reported to be 2.6 km.

For all of these scenarios, the report indicates that the distances exceed the 500 m safety zone but are less than the Applicant's proposed 2 NM (3.7 km) designated Area to be Avoided.

There are several aspects of the analysis in the Draft EIS/EIR that may work to significantly underestimate these hazard distances.

The analysis in the Draft EIS/EIR is based on a computer model which has not been verified or validated for this application. Although the Fire Dynamics Simulator (FDS) is a sophisticated computer model which has been studied with regard to simulation of fires, its stated intended purposes include:

- Low speed transport of heat and combustion products from fire
- radiative and convective heat transfer between the gas and solid surfaces

- Pyrolysis
- Flame spread and fire growth
- Sprinkler and heat detector activation
- Sprinkler sprays and suppression by water

from page 6 of "Fire Dynamics Simulator (Version 4) Technical Reference Guide," NIST Special Publication 1018, Kevin McGrattan, editor. Specifically, FDS has not been verified for the purpose of predicting the dispersion of LNG vapor. It is well established that denser-than-air gases such as LNG vapor behave according to different physical rules than are used in FDS. Furthermore, FDS has not been validated against the extensive available data pertaining to the dispersion of denser-than-air contaminants such as LNG vapor.

The assumptions used to model the consequences in the Draft EIS/EIR are not conservative as presumed in the report. Although the Draft EIS/EIR reassures the reader that the assumptions made in the hazard assessment are conservative, there is no documentation of this assertion. Furthermore, whether some of the assumptions are conservative or not may be based on the choice of the FDS to model the LNG vapor dispersion. Based on my experience, the following assumptions are questionable:

- Wind speed and atmospheric stability of 6 m/s and D stability give longer downwind distances that 2 m/s and F stability. This assertion would not be valid for models specified in federal regulations for determination of the vapor dispersion hazards of LNG.
- LNG does not evaporate as it spreads. In addition to this assumption being vague, it is physically impossible, computationally unnecessary, and very questionable as to whether it is even conservative in the sense used in the report.

In addition to these assumptions about the model inputs, the Draft EIS/EIR makes assumptions about the criteria used to determine the hazard distance which are inconsistent with other standards and regulations. The Executive Summary lists 49 CFR 193 as part of the "Key Elements and Thresholds" used in preparation of the report (page ES-15) and states that 49 CFR 193 "mandates compliance with American National Standards Institute/National Fire Protection Association (ANSI/NFPA) 59A, Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)." For on-shore facilities, 49 CFR 193 and NFPA 59A require the determination of exclusion zones for thermal hazard distances be based on thermal radiation levels of 5 kW/m^2. In a report prepared for the Federal Energy Regulatory Commission (FERC), ABS Consulting reports that the thermal radiation level of 5 kW/m^2 would be expected to produce second degree burns after 30 s exposure and third-degree burns (1% fatality) after 50 s exposure. For on-shore facilities, 49 CFR 193 and NFPA 59A also require the determination of exclusion zones for vapor hazard distances be based in LNG vapor concentrations of 2.5%

(LFL/2). Since the Draft EIS/EIR uses higher thermal radiation and concentration levels to determine the hazards, its consequence assessments are not conservative.

More appropriate models are available to predict the thermal and vapor cloud hazards than were used in the Draft EIS/EIR. There are models available which take into account the appropriate physical principles that govern the dispersion of denser-than-air gases such as LNG vapor and are referenced in 49 CFR 193 and NFPA 59A. Such modeling questions have been recently revisited by FERC. Under contract number FERC 04C40196, ABS Consulting summarized methods for determining thermal radiation and vapor dispersion hazards for LNG spills on water. The pertinent reports from this work are "Consequence Assessment Methods for Incidents Involving Releases from Liquefied Natural Gas Carriers" (dated 13 May 2004) and "Notice of Availability of Detailed Computations for the Consequence Assessment Methods for Incidents Involving Releases from Liquefied Natural Gas Carriers" (dated 29 June 2004) as part of FERC Docket No. AD-04-6-0000. Notwithstanding my concerns about the validity of the meteorological conditions of 6 m/s and D stability as representing the worst case conditions, I prepared estimates of the two worst case scenarios using the methods prescribed by the FERC report as summarized in the Table below (using the 6 m/s wind speed and D stability).

Worst-Case Credible Releases
Hazard Distances from FSRU

	Case 1	Case 2
Thermal radiation hazard distance	2.3 km	2.6 km
Vapor dispersion hazard distance	9.4 km	11.9 km

These hazard distances exceed the 500 m safety zone radius around the FSRU as well as the Applicant's proposed Area to be Avoided of 2 NM (3.7 km). I did not make calculations for scenario TA-A because I do not believe that the instantaneous release of the contents of all three tanks while fully loaded is a credible event (also the position stated in the Draft EIS/EIR. However, I do believe that the instantaneous release of the contents of two tanks while fully loaded should be considered. Such a scenario could occur because of a fire from either of the worst case scenarios discussed in the Draft EIS/EIR. If such a fire were to occur and not be controlled, the fire could compromise the insulation systems on the remaining two tanks thereby threatening their integrity. Such a potential hazard does not seem to be addressed in the Draft EIS/EIR.

In summary, the Draft EIS/EIR was prepared to address the objectives quoted at the beginning of this letter. I believe the report fails to meet the stated objectives in several very important ways with regard to thermal radiation and vapor dispersion hazards.

Sincerely,

T. Spicer

Thomas O. Spicer, III, PhD, PE
Consulting Chemical Engineer